

Environmental Protection Agency

§ 98.254

vapor-phase methane concentration of 0.5 volume percent or more using tank-specific methane composition data (from measurement data or product knowledge) and the AP-42 emission estimation methods provided in Section 7.1 of the AP-42: "Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources", including TANKS Model (Version 4.09D) or similar programs, or estimate CH₄ emissions from storage tanks using Equation Y-22 of this section.

$$CH_4 = (0.1 \times Q_{Ref}) \quad (\text{Eq. Y-22})$$

Where:

CH₄ = Annual methane emissions from storage tanks (metric tons/year).

0.1 = Default emission factor for storage tanks (metric ton CH₄/MMbbl).

Q_{Ref} = Quantity of crude oil plus the quantity of intermediate products received from off site that are processed at the facility (MMbbl/year).

(2) For storage tanks that process unstabilized crude oil, calculate CH₄ emissions from the storage of unstabilized crude oil using either tank-specific methane composition data (from measurement data or product knowledge) and direct measurement of the gas generation rate or by using Equation Y-23 of this section.

$$CH_4 = (995,000 \times Q_{un} \times \Delta P) \times MF_{CH_4} \times \frac{16}{MVC} \times 0.001 \quad (\text{Eq. Y-23})$$

Where:

CH₄ = Annual methane emissions from storage tanks (metric tons/year).

Q_{un} = Quantity of unstabilized crude oil received at the facility (MMbbl/year).

ΔP = Pressure differential from the previous storage pressure to atmospheric pressure (pounds per square inch, psi).

MF_{CH₄} = Mole fraction of CH₄ in vent gas from the unstabilized crude oil storage tank from facility measurements (kg-mole CH₄/kg-mole gas); use 0.27 as a default if measurement data are not available.

995,000 = Correlation Equation factor (scf gas per MMbbl per psi).

16 = Molecular weight of CH₄ (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf/kg-mole).

0.001 = Conversion factor (metric ton/kg).

(3) You do not need to calculate CH₄ emissions from storage tanks that meet any of the following descriptions:

(i) Units permanently attached to conveyances such as trucks, trailers, rail cars, barges, or ships;

(ii) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere;

(iii) Bottoms receivers or sumps;

(iv) Vessels storing wastewater; or

(v) Reactor vessels associated with a manufacturing process unit.

(n) For crude oil, intermediate, or product loading operations for which the equilibrium vapor-phase concentration of methane is 0.5 volume percent

or more, calculate CH₄ emissions from loading operations using product-specific, vapor-phase methane composition data (from measurement data or process knowledge) and the emission estimation procedures provided in Section 5.2 of the AP-42: "Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources." For loading operations in which the equilibrium vapor-phase concentration of methane is less than 0.5 volume percent, you may assume zero methane emissions.

§ 98.254 Monitoring and QA/QC requirements.

(a) Fuel flow meters, gas composition monitors, and heating value monitors associated with stationary combustion sources must follow the monitoring and QA/QC requirements in § 98.34.

(b) All flow meters, gas composition monitors, and heating value monitors that are used to provide data for the GHG emissions calculations in this subpart for sources other than stationary combustion sources shall be calibrated according to the procedures in the applicable methods specified in paragraphs (c) through (e) of this section, the procedures specified by the manufacturer, or §§ 98.3(i). Recalibrate each flow meter either biennially

(every two years) or at the minimum frequency specified by the manufacturer. Recalibrate each gas composition monitor and heating value monitor either annually or at the minimum frequency specified by the manufacturer.

(c) For flare or sour gas flow meters, operate and maintain the flow meter using any of the following methods, a method published by a consensus-based standards organization (e.g., ASTM, API, etc.) or follow the procedures specified by the flow meter manufacturer. Flow meters must have a rated accuracy of ± 5 percent or lower.

(1) ASME MFC-3M-2004 Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi (incorporated by reference, *see* § 98.7).

(2) ASME MFC-4M-1986 (Reaffirmed 1997) Measurement of Gas Flow by Turbine Meters (incorporated by reference, *see* § 98.7).

(3) ASME MFC-6M-1998 Measurement of Fluid Flow in Pipes Using Vortex Flowmeters (incorporated by reference, *see* § 98.7).

(4) ASME MFC-7M-1987 (Reaffirmed 1992) Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles (incorporated by reference, *see* § 98.7).

(5) ASME MFC-11M-2006 Measurement of Fluid Flow by Means of Coriolis Mass Flowmeters (incorporated by reference, *see* § 98.7).

(6) ASME MFC-14M-2003 Measurement of Fluid Flow Using Small Bore Precision Orifice Meters (incorporated by reference, *see* § 98.7).

(7) ASME MFC-18M-2001 Measurement of Fluid Flow Using Variable Area Meters (incorporated by reference, *see* § 98.7).

(8) AGA Report No. 11 Measurement of Natural Gas by Coriolis Meter (2003) (incorporated by reference, *see* § 98.7).

(d) Determine flare gas composition using any of the following methods.

(1) Method 18 at 40 CFR part 60, appendix A-6.

(2) ASTM D1945-03 Standard Test Method for Analysis of Natural Gas by Gas Chromatography (incorporated by reference, *see* § 98.7).

(3) ASTM D1946-90 (Reapproved 2006) Standard Practice for Analysis of Reformulated Gas by Gas Chromatography (incorporated by reference, *see* § 98.7).

(4) GPA 2261-00 Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography (incorporated by reference, *see* § 98.7).

(5) UOP539-97 Refinery Gas Analysis by Gas Chromatography (incorporated by reference, *see* § 98.7).

(e) Determine flare gas higher heating value using any of the following methods.

(1) ASTM D4809-06 Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method) (incorporated by reference, *see* § 98.7).

(2) ASTM D240-02 (Reapproved 2007) Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (incorporated by reference, *see* § 98.7).

(3) ASTM D1826-94 (Reapproved 2003) Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter (incorporated by reference, *see* § 98.7).

(4) ASTM D3588-98 (Reapproved 2003) Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels (incorporated by reference, *see* § 98.7).

(5) ASTM D4891-89 (Reapproved 2006) Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion (incorporated by reference, *see* § 98.7).

(f) For exhaust gas flow meters used to comply with the requirements in § 98.253(c)(2)(ii), install, operate, calibrate, and maintain exhaust gas flow meter according to the requirements in 40 CFR 63.1572(c) or according to the following requirements.

(1) Locate the flow meter(s) and other necessary equipment such as straightening vanes in a position that provides representative flow; reduce swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

(2) Use a flow rate meter with an accuracy within ± 5 percent.

(3) Use a continuous monitoring system capable of correcting for the temperature, pressure, and moisture content to output flow in dry standard cubic feet (standard conditions as defined in § 98.6).

(4) Install, operate, and maintain each continuous monitoring system according to the manufacturer's specifications and requirements.

(g) For exhaust gas CO₂/CO/O₂ composition monitors used to comply with the requirements in § 98.253(c)(2), install, operate, calibrate, and maintain exhaust gas composition monitors according to the requirements in 40 CFR 60.105a(b)(2) or 40 CFR 63.1572(a) or according to the manufacturer's specifications and requirements.

(h) Determine the mass of petroleum coke as required by Equation Y-13 of this subpart using mass measurement equipment meeting the requirements for commercial weighing equipment as described in Specifications, Tolerances, and Other Technical Requirements For Weighing and Measuring Devices, NIST Handbook 44 (2009) (incorporated by reference, see § 98.7). Calibrate the measurement device according to the procedures specified by the method, the procedures specified by the manufacturer, or § 98.3(i). Recalibrate either biennially or at the minimum frequency specified by the manufacturer.

(i) Determine the carbon content of petroleum coke as required by Equation Y-13 of this subpart using any one of the following methods. Calibrate the measurement device according to procedures specified by the method or procedures specified by the measurement device manufacturer.

(1) ASTM D3176-89 (Reapproved 2002) Standard Practice for Ultimate Analysis of Coal and Coke (incorporated by reference, see § 98.7).

(2) ASTM D5291-02 (Reapproved 2007) Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants (incorporated by reference, see § 98.7).

(3) ASTM D5373-08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, see § 98.7).

(j) Determine the quantity of petroleum process streams using company records. These quantities include the quantity of asphalt blown, quantity of crude oil plus the quantity of intermediate products received from off

site, and the quantity of unstabilized crude oil received at the facility.

(k) The owner or operator shall document the procedures used to ensure the accuracy of the estimates of fuel usage, gas composition, and heating value including but not limited to calibration of weighing equipment, fuel flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices shall also be recorded, and the technical basis for these estimates shall be provided.

(l) All CO₂ CEMS and flow rate monitors used for direct measurement of GHG emissions must comply with the QA procedures in § 98.34(c).

§ 98.255 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required (e.g., concentrations, flow rates, fuel heating values, carbon content values). Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a CEMS malfunctions during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations.

(a) For stationary combustion sources, use the missing data procedures in subpart C of this part.

(b) For each missing value of the heat content, carbon content, or molecular weight of the fuel, substitute the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If the "after" value is not obtained by the end of the reporting year, you may use the "before" value for the missing data substitution. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(c) For missing CO₂, CO, O₂, CH₄, or N₂O concentrations, gas flow rate, and percent moisture, the substitute data values shall be the best available estimate(s) of the parameter(s), based on all available process data (e.g., processing rates, operating hours, etc.). The